VOLUME VIII: CHAPTER 14

METHODS FOR ESTIMATING METHANE AND NITROUS OXIDE EMISSIONS FROM STATIONARY COMBUSTION

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DISCLAIMER

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CONTENTS

TABLES

1

INTRODUCTION

The purposes of the preferred methods guidelines are to describe emissions estimation techniques for greenhouse gas sources in a clear and unambiguous manner and to provide concise example calculations to aid in the preparation of emission inventories. This chapter describes the procedures and recommended approaches for estimating nitrous oxide (N_2O) and methane (CH_4) emissions from stationary combustion.[1]

Section 2 of this chapter contains a general description of the stationary combustion source category. Section 3 provides a listing of the steps involved in using the preferred method for estimating greenhouse gas emissions from this source. Section 4 presents the preferred estimation methods; Section 5 is a placeholder section for alternative estimation techniques that may be added in the future. Quality assurance and quality control procedures are described in Section 6. References used in developing this chapter are identified in Section 7.

[1] Chapter 1 of this volume provides methods for estimating CO_2 emissions from combustion sources.

2

SOURCE CATEGORY DESCRIPTION

2.1 EMISSION SOURCES

Combustion of fuels at stationary sources results in emissions of five non-CO_2 GHGs: CH_4, N_2O, CO, NO_X, and non-methane volatile organic compounds (NMVOCs). For the first two of these GHGs (CH_4 and N_2O), global warming potential values (GWPs) have been developed, which allow for normalization of all emissions to a common unit of metric tons of carbon equivalent. No GWPs have yet been developed for the other three types of gases (CO, NO_X, and NMVOCs); thus, they cannot be included in a GHG inventory. Consequently, this chapter describes how to estimate emissions only of N_2O and CH_4 from fuel combustion at stationary sources.

Other than N_2O, the amount of gases emitted from these activities are not thought to be major contributors to climate change. Data on gases such as CO, NO_X, and NMVOCs are already collected by state environmental or air quality agencies to determine state compliance with Clean Air Act regulations.

2.2 FACTORS INFLUENCING EMISSIONS

In general, emissions of these gases will vary with the size and vintage of the combustion technology, how it is maintained and operated, and any pollution control technology used.

N_2O is produced from the combustion of fuels, and the mechanisms of its formation are fairly well understood. The level of N_2O emissions depends on the combustion temperature, with the highest N_2O emissions at a temperature of 1000 degrees Kelvin. For combustion temperatures below 800 or above 1200 degrees Kelvin, the N_2O emissions are negligible. (IPCC 1997)

Methane, NMVOCs, and CO are unburned gaseous combustibles that are emitted in small quantities due to incomplete combustion; more of these gases are released when combustion temperatures are relatively low. Emissions of these gases are also influenced by technology type, size, vintage, maintenance, operation, and emission controls. Larger, higher efficiency combustion facilities tend to have higher temperatures and thus, lower emission factors for these gases. Emissions may range several orders of magnitude above the average for facilities that are improperly maintained or poorly operated, such as may be the case for many older units. Similarly, during start-up periods, combustion efficiency is lowest, and CO and VOC emissions are higher than during periods of full operation.

3

OVERVIEW OF AVAILABLE METHODS

The methodology to estimate N_2O and CH_4 emissions from stationary source fuel combustion involves the following steps: (1) obtain the required data on fuel consumption in each sector; (2) multiply the amounts of fuel by the appropriate emission factors; and (3) sum across all fuels and sectors to derive total emissions.

Analysts should note before proceeding with this chapter that these calculations can be time consuming. Although a simple method is available for estimating N_2O emissions, the complex method for estimating CH_4 emissions (and, at the analyst's option, N_2O emissions) requires estimating, for each industry sector, the proportions of each fuel combusted using various combustion technologies. The analysis should be conducted by creating and using a spreadsheet that performs the calculations described in Section 4.

The estimation method described here is the "Tier 2" method developed by the Intergovernmental Panel on Climate Change (IPCC 1997). This method is consistent with the method used in the U.S. greenhouse gas inventory (U.S. EPA 1998).

Methods for developing greenhouse gas inventories are continuously evolving and improving. The methods presented in this volume represent the work of the EIIP Greenhouse Gas Committee in 1998 and early 1999. This volume takes into account the guidance and information available at the time on inventory methods, specifically, U.S. EPA's *State Workbook: Methodologies for Estimating Greenhouse Gas Emissions* (U.S.EPA 1998a), volumes 1-3 of the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 1997), and the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1996* (U.S. EPA 1998b).

There have been several recent developments in inventory methodologies, including:

- Publication of EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 1997* (U.S. EPA 1999) and completion of the draft inventory for 1990 – 1998. These documents will include methodological improvements for several sources and present the U.S. methodologies in a more transparent manner than in previous inventories;
- Initiation of several new programs with industry, which provide new data and information that can be applied to current methods or applied to more accurate and reliable methods (so called "higher tier methods" by IPCC); and
- The IPCC Greenhouse Gas Inventory Program's upcoming report on Good Practice in Inventory Management, which develops good practice guidance for the implementation of the 1996 IPCC Guidelines. The report will be published by the IPCC in May 2000.

Note that the EIIP Greenhouse Gas Committee has not incorporated these developments into this version of the volume. Given the rapid pace of change in the area of greenhouse gas inventory methodologies, users of this document are encouraged to seek the most up-to-date information from EPA and the IPCC when developing inventories. EPA intends to provide periodic updates to the EIIP chapters to reflect important methodological developments. To determine whether an updated version of this chapter is available, please check the EIIP site at http://www.epa.gov/ttn/chief/eiip/techrep.htm#green.

4

PREFERRED METHODS FOR ESTIMATING EMISSIONS

Estimation of emissions from stationary sources can be described using the following basic formula, which indicates that total emissions for a particular state equals the sum of emissions across activities, technologies, and fuel types.

$$\text{Emissions} = \Sigma\ (EF_{abc} \times \text{Activity}_{abc} \times (100\text{-}R_{abc})/100)$$

where:
EF = Emission Factor (kg/terajoule[2]);
Activity = Energy Input (terajoules);
R_{abc} = Percentage reduction in emissions due to controls;
a = Fuel type;
b = Sector activity; and
c = Technology type.

As seen in this equation, emission estimation is based on three sets of data, each of which vary by fuel type, sector, and technology: (1) energy activities; (2) emissions factors; and (3) control technologies.

In addition, this section presents a simpler method for estimating N_2O emissions, based on the total amount of coal, oil, and natural gas used for stationary source combustion in a state.

This section presents the steps involved in using this methodology.

Step (1) Obtain Activity Data

- *Required Data*. The required data are the amounts of coal, petroleum, natural gas, and wood combusted in the residential, commercial, industrial, and utility sectors.

- *Data Sources*: In-state agencies should be consulted first. However, if it is difficult to obtain data from these sources, state-by-state data may be found in the *State Energy Data Report* (U.S. DOE/EIA 1997). Stationary sources have been divided into five sectors in EIA data sources: industry, agriculture, commercial, residential, and electric utilities.[3]

[2] A terajoule equals 10^{12} joules.
[3] Transportation is another sector frequently encountered in energy consumption statistics, but is not a stationary source. Transportation sector emissions of other greenhouse gases are addressed as mobile source emissions (see Chapter 13).

- *Units for Reporting* Data: Data should be provided in British thermal units (Btu) or terajoules. (Some of the emission factors provided in this chapter require activity levels reported in Btu; others require activity levels reported in terajoules. A conversion factor from Btus to terajoules is provided in Step 6 below.) If data are presented in units of barrels, tons, or billion cubic feet, convert to Btu using the conversion factors in Table 14.4-1.

Step (2) Convert Data to Reflect Lower Heating Values

If the data are reported in higher heating values (as are data reported by the US Department of Energy), convert the values from higher heating values (gross calorific values) to lower heating values (net calorific values). The difference between the higher and lower heating value of a fuel is the heat of condensation of moisture in the fuel during combustion. The lower heating value excludes this. Since most of the world uses net calorific values, the IPCC emission factors, used later in this chapter, are based on net calorific values.

- For petroleum products and coal, the net calorific values are about five percent lower than gross calorific values. Thus, for petroleum products, coal, and wood (or other biomass), multiply the higher heating values (gross calorific values) by 0.95 to obtain lower heating values (net calorific values). For natural gas, which contains more moisture, multiply the higher heating values (gross calorific values) by 0.90 to obtain lower heating values (net calorific values).

Example	In a hypothetical state, fuels used for stationary combustion, measured by their higher heating values, were 21 trillion Btu of coal, 42 trillion Btu of oil, and 66 trillion Btu of natural gas. The calculations to convert these values to lower heating values are as follows: 21 trillion Btu coal (higher heating value) × 0.95 = **20 trillion Btu coal** (lower heating value) 42 trillion Btu oil (higher heating value) × 0.95 = **40 trillion Btu oil** (lower heating value) 66 trillion Btu natural gas (higher heating value) × 0.90 = **60 trillion Btu natural gas** (lower heating value).

Step (3) Choose One of Two Methods for Estimating N_2O Emissions

- Decide whether to estimate N_2O emissions based on the set of three emission factors in Table 14.4-2, or based on the more complex set of emission factors in Tables 14.4-3 through 14.4-7. If your state has data only for the total amount of coal, oil, and natural gas combusted by stationary sources in the state, you may use the emission factors in Table 14.4-2, and calculate only N_2O emissions (this table does not provide emission factors for CH_4). If your state has data on the amount of coal, oil, natural gas, and other fuels combusted by each type of stationary source, you may use the emission factors in Tables 14.4-3 through 14.4-7 to estimate N_2O emissions as well as CH_4 emissions.

- If using the three emission factors in Table 14.4-2, follow Step 4 for N_2O and Steps 5 through 8 for CH_4.

- If using the more complex set of emission factors, follow the methodology set forth in steps 5 through 8 for both N_2O and CH_4.

Step (4) Simple method for estimating N_2O emissions (if using the complex method to estimate N_2O emissions, skip to Step 5)

- Perform the multiplication for each fuel type to obtain N_2O emissions in pounds, sum the results across all three fuels, and convert to metric tons of N_2O by dividing by 2205 pounds per metric ton.

- Convert the data from metric tons of gas to metric tons of carbon equivalent, by multiplying by (1) the mass ratio of carbon to carbon dioxide (12/44), and (2) the global warming potential for N_2O, i.e., 310.

Example In a hypothetical state, fuels used for stationary combustion were 20 trillion Btu of coal, 40 trillion Btu of oil, and 60 trillion Btu of natural gas (all values are lower heating, or net calorific values). N_2O emissions would be estimated using the simple method (Table 14.4-2) as follows:

Coal

20 trillion Btu $\times$ (10^{12} Btu/1 trillion Btu) $\times$ (1 million Btu/10^6 Btu) = 20 $\times$ 10^6 million Btu

20 $\times$ 10^6 million Btu $\times$ 0.0032 pounds/million Btu = 64,000 pounds of N_2O

Oil

40 trillion Btu $\times$ (10^{12} Btu/1 trillion Btu) $\times$ (1 million Btu/10^6 Btu) = 40 $\times$ 10^6 million Btu

40 $\times$ 10^6 million Btu $\times$ 0.0014 pounds/million Btu = 56,000 pounds of N_2O

Natural Gas

60 trillion Btu $\times$ (10^{12} Btu/1 trillion Btu) $\times$ (1 million Btu/10^6 Btu) = 60 $\times$ 10^6 million Btu

60 $\times$ 10^6 million Btu $\times$ 0.0002 pounds/million Btu = 12,000 pounds of N_2O

Total

Total N_2O emissions from fuel combustion for the utility sector =

(64,000 + 56,000 + 12,000) pounds of N_2O = 132,000 pounds of N_2O

132,000 pounds of N_2O $\times$ (metric ton/2205 pounds) = 60 metric tons of N_2O

60 metric tons of N_2O $\times$ 12/44 $\times$ 310 (GWP for N_2O) = **5,100 MTCE**

Step (5) Apportion stationary combustion fuel use by sector and combustion technology (use for CH_4; use for N_2O only if using Tables 14.4-3 through 14.4-7)

- Apportion the state's energy consumption by stationary sources (measured as lower heating values) into the sector categories and technology subcategories shown in Tables 14.4-3 through 14.4-7, and further apportion these values by the types of pollution control used, as shown in Tables 14.4-8 through 14.4-11. Note that the latter apportionment may require making assumptions about the distribution of pollution control technologies for each combustion technology. In making the latter apportionment, a simplifying approach would be to group together all pollution control technologies for which data on CH_4 and N_2O reductions are not provided in Tables 14.4-8 through 14.4-11.[4]
- If using an alternative data source for emission factors, apportion energy consumption into the categories specified in the alternative data source.

Step (6) Convert units to terajoules (use for CH_4; use for N_2O only if using Tables 14.4-3 through 14.4-7)

Convert the fuel consumption values (lower heating values) to units of terajoules of fuel.

[4] Note that the emission control performance is negligible for most technologies for both N_2O and CH_4.

- If values are in million Btu, use the ratio of one terajoule per 947.8 million Btus.

Example A hypothetical state's utility sector used 10 trillion Btu of coal (lower heating value) in dry bottom, wall-fired boilers, with half of that used in boilers using low NO_x burners for emission controls. To convert the units to terajoules, perform the following calculations:

10 trillion Btu × (10^{12} Btu/1 trillion Btu) × (1 million Btu/10^6 Btu) = 10 × 10^6 million Btu

10 × 10^6 million Btu × (1 terajoule/947.8 million Btu) =10,550 terajoules

½ of 10,550 terajoules = **5,275 terajoules used in each type of boiler** (with and without low NO_x burners)

Step (7) Multiply the energy consumption values by the appropriate emission factors and adjust for emission control performance (use for CH_4; use for N_2O only if using Tables 14.4-3 through 14.4-7)

- To estimate CH_4 emissions, multiply the energy consumption by each subcategory of stationary sources (in terajoules) by (1) the respective emission factors for CH_4 (in kg/terajoule), and (2) a value of ((100 - the emissions control performance for CH_4)/100). Emission control performance values are provided in Tables 14.4-8 through 14.4-11. Sum the emissions of CH_4 across all subcategories to obtain total CH_4 emissions (in kilograms).

- Repeat the analysis for N_2O emissions, using the respective emission factors for N_2O and the emissions control performance for N_2O.

Example A hypothetical state uses 5,275 terajoules of coal in dry bottom, wall-fired utility boilers without emission controls, and the same amount in the same type of boilers with low NO_x burners. To estimate N_2O emissions from utility coal combustion, perform the following calculations:

For boilers without emission control, simply multiply energy consumption by the emission factor for N_2O (use the factor for dry bottom, wall-fired boilers):

(5,275 TJ) × (0.7 kg CH_4/TJ) = 3,700 kg CH_4

For boilers with emissions control, adjust for emissions control performance (note that in Table 14.4-8, all CH_4 emissions reductions associated with performance controls are negligible)*:*

(5,275 TJ) × (0.7 kg CH_4/TJ) × ((100 - 0)/100) = 3,700 kg CH_4

Total

(3,700 + 3,700) kg CH_4 = **7,400 kg CH_4**

Step (8) Convert the values from kilograms to metric tons of carbon equivalent (use for CH_4; use for N_2O only if using Tables 14.4-3 through 14.4-7)

Convert the data from kilograms of gas to metric tons of carbon equivalent (MTCE).

- First, convert to metric tons of gas by dividing the number of kilograms of gas by 1,000. Then convert to MTCE by multiplying by (1) the mass ratio of carbon to carbon dioxide (12/44), and (2) the global warming potential (GWP) for each gas. The GWP for CH_4 is 21, and the GWP for N_2O is 310.

Example To convert emissions data from kg of CH_4 to MTCE, perform the following calculations:

7,400 kg $CH_4 \times$ (metric ton/1,000 kg) = 7.4 metric tons CH_4

7.4 metric tons $CH_4 \times$ (12/44) $\times$ 21 (GWP for CH_4) = **42 MTCE**

Table 14.4-1 Factors to Convert Units to Million Btu[a]
[Note: Step 6 provides the ratio to convert million Btu to terajoules]

Fuel Type	If data are in	Multiply by
Petroleum		
Asphalt and Road Oil	barrels	6.636
Aviation Gasoline	barrels	5.048
Distillate Fuel Oil	barrels	5.825
Jet Fuel: Kerosene Type	barrels	5.670
Jet Fuel: Naphtha Type	barrels	5.355
Kerosene	barrels	5.670
Liquefied Petroleum Gases	barrels	4.011
Lubricants	barrels	6.065
Miscellaneous Petroleum Products and Crude Oil	barrels	5.800
Motor Gasoline	barrels	5.253
Naphtha[b] and Special Naphthas	barrels	5.248
Other Oil[b] and Unfinished Oils	barrels	5.825
Pentane Plus	barrels	4.620
Petroleum Coke	barrels	6.024
Residual Fuel Oil	barrels	6.287
Still Gas[b]	barrels	6.000
Waxes	barrels	5.537
Coal[c]		
Anthracite[d]	short tons	21.668
Bituminous	short tons	23.89
Sub-bituminous	short tons	17.14
Lignite	short tons	12.866
Coal Coke	short tons	24.800
Natural Gas	billion cubic feet	$1.03 \times 1,000,000$
	Teracalories	3968

a. Heat contents of many fuels vary somewhat by source, year, and consumer. Except for coal and blended petroleum products, this variation tends to be relatively small. The values here are national averages for 1990.
b. By EIA definition, naphtha, other oil, and still gas are collectively termed petrochemical feedstocks.
c. Thermal conversion factors for coal can vary extensively by source. More complete state and sector specific factors are available through EIA.
d. The anthracite factor presented here is a national average. Actual anthracite factors could range from as low as 17.5 MMBtu/ton for anthracite reclaimed from refuse piles to 26 MMBtu/ton or higher for anthracite mined directly from the original seam.

Source: Petroleum and natural gas heat-equivalents are from EIA's *Annual Energy Review* (EIA 1997d). Coal heat-equivalents are from EIA's *State Energy Data Report* (EIA 1997c), *Cost and Quality of Fuels for Electric Utility Plants* (EIA 1997a), and *Quarterly Coal Report* (EIA 1997b).

Table 14.4-2

N_2O Emissions Factors For Conventional Facilities, By Fuel Type

Fuel	Emission Factor (lbs/10^6Btu)	Uncertainty Range
Coal	0.0032	0 - 0.0234
Oil	0.0014	0 - 0.0065
Gas	0.0002	0 - 0.0026

Source: De Soete (1993) as cited in IPCC (1994)

TABLE 14.4-3
UTILITY BOILER SOURCE PERFORMANCE

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Pulverised Bituminous Combustion	Dry Bottom, wall fired	9	0.7	380	1.6	NAV
	Dry Bottom, tangentially fired	9	0.7	250	0.5	NAV
	Wet Bottom	9	0.9	590	1.6	NAV
Bituminous Spreader Stokers	With and without re-injection	87	1.0	240	1.6	NAV
Bituminous Fluidised Bed Combustor	Circulating Bed	310	1.0	68	96	NAV
	Bubbling Bed	310	1.0	270	96	NAV
Bituminous Cyclone Furnace		9	0.2	590	1.6	NAV
Anthracite Stokers		10	NAV	160	NAV	NAV
Anthracite Fluidised Bed Combustors		5.2	NAV	31	NAV	NAV
Anthracite Pulverised Coal Boilers		310	NAV	NAV	NAV	NAV
Pulverised Lignite Combustion	Dry Bottom, tangentially fired	NAV	NAV	130	NAV	NAV
	Dry Bottom, wall fired	45	NAV	200	NAV	NAV
Lignite Cyclone Furnace		NAV	NAV	220	NAV	NAV
Lignite Spreader Stokers		NAV	NAV	100	NAV	NAV
Lignite Atmospheric Fluidised Bed		2.8	NAV	63	42	NAV
Oil						
Residual Fuel Oil/Shale Oil	Normal Firing	15	0.9	200	0.3	NAV
	Tangential Firing	15	0.9	130	0.3	NAV
Distillate Fuel Oil	Normal Firing	16	0.9	220	0.4	NAV
	Tangential Firing	16	0.9	140	0.4	NAV
Distillate Fuel Gaseous Turbines		21	NAV	300	NAV	NAV
Large Diesel Fuel Engines >600hp (447kW)		350	4.0	1300	NAV	NAV
Natural Gas						
Boilers		18	0.1[a]	250	NAV	NAV
Large Gas-Fired Gas Turbines >3MW		46	6*	190	NAV	NAV
Large Dual-Fuel Engines		340	240	1300	NAV	NAV
Municipal Solid Waste (MSW)						
Mass Burn Waterwall Combustors		22	NAV	170	NAV	NAV
MSW - Mass Feed[a]		98	NAV	140	NAV	NAV

Source: US EPA (1995).
(a) Adapted from Radian, 1990.

Note: large dual-fuel engines are large engines that can run on either natural gas or oil. "Large" is typically defined for regulatory purposes as having a capacity to combust more than 250 mmbtu/hr of fuel; an alternative, equivalent definition is having a capacity to generate about 25 megawatts of power.

TABLE 14.4-4
INDUSTRIAL BOILER PERFORMANCE

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Bit./Sub-bit. Overfeed Stoker Boilers		110	1.0	130	1.6	NAV
Bit./Sub-bit. Underfeed Stoker Boilers		190	14	170	1.6	NAV
Bit./Sub-bit. Hand-fed Units		4800	87	160	1.6	NAV
Bituminous/Sub-bituminous Pulverised	Dry Bottom, wall fired	9	0.7	380	1.6	NAV
	Dry Bottom, tangentially fired	9	0.7	250	0.5	NAV
	Wet Bottom	9	0.9	590	1.6	NAV
Bituminous Spreader Stokers		87	1.0	240	1.6	NAV
Bit./Sub-bit. Fluidised Bed Combustor	Circulating Bed	310	1.0	68	96	NAV
	Bubbling Bed	310	1.0	270	96	NAV
Anthracite Stokers		10	NAV	160	NAV	NAV
Anthr. Fluidised Bed Combustor Boilers		5.2	NAV	31	NAV	NAV
Anthracite Pulverised Coal Boilers		NAV	NAV	310	NAV	NAV
Oil						
Residual Fuel Oil Boilers		15	3.0	170	0.3	NAV
Distillate Fuel Oil Boilers		16	0.2	65	0.4	NAV
Small Waste Oil Boilers <0.1MW		15	NAV	58	NAV	NAV
LPG Boilers	Propane	17	NAV	96	NAV	NAV
	Butane	16	NAV	97	NAV	NAV
Small Stationary Internal Comb. Engines	Gasoline <250hp (186 kW)	27	NAV	0.7	NAV	NAV
	Diesel <600hp (447 kW)	0.4	NAV	1.9	NAV	NAV
Large Stationary Diesel Engines >600hp (447 kW)		0.3	0.0	1.3	NAV	NAV
Natural Gas						
Large Boilers >100 MBtu/h (293 MW)		18	1.4	250	NAV	NAV
Small Boilers 10-100 MBtu/h (29.3-293 MW)		16	1.4	64	NAV	NAV
Heavy Duty Nat. Gas Compressor Eng.	Turbines	2.0	0.6	4.1	NAV	NAV
	2-Cycle Lean Burn	4.7	17	33	NAV	NAV
	4-Cycle Lean Burn	5.1	13	39	NAV	NAV
	4-Cycle Rich Burn	20	2.9	28	NAV	NAV
Wood						
Fuel Cell/Dutch Oven Boilers		290	NAV	17	NAV	NAV
Stoker Boilers		590	15	65	NAV	NAV
FBC Boilers		61	NAV	87	NAV	NAV
Bagasse/Ag. Waste Boilers		NAV	NAV	68	NAV	NAV
MSW						
MSW Boilers	Mass Burn Waterwall	22	NAV	170	NAV	NAV
	Mass Burn Rotary Waterwall	36	NAV	110	NAV	NAV
	Mass Burn Rotary Refrac. Wall	64	NAV	120	NAV	NAV
	Modular, Excess Air	NAV	NAV	120	NAV	NAV
	Modular, Starved Air	14	NAV	150	NAV	NAV
Refuse Derived Combustors		90	NAV	240	NAV	NAV

Source: US EPA (1995).

TABLE 14.4-5
KILNS, OVENS, AND DRYERS SOURCE PERFORMANCE

		Emission Factors (kg/TJ energy input)[a]				
Industry	**Source**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Cement, Lime	Kilns - Natural Gas	83	1.1	1,111	NAV	NAV
Cement, Lime	Kilns - Oil	79	1.0	527	NAV	NAV
Cement, Lime	Kilns - Coal	79	1.0	527	NAV	NAV
Coking, Steel	Coke Oven	211	1	35[b]	NAV	16[b]
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	11	1.1	64	NAV	NAV
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Oil	16	1.0	168	NAV	NAV
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Coal	179	1.0	226	NAV	NAV

Source: Radian, 1990.

(a) Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific values were 5 per cent lower than gross calorific values for coal and oil, and 10 per cent lower for natural gas. These percentage adjustments are the OECD/IEA assumption on how to convert from gross to net calorific values.

(b) Joint EMEP/CORINAIR (1996).

TABLE 14.4-6 RESIDENTIAL SOURCE PERFORMANCE						
		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Anthracite Space Heaters		NAV	150	55	NAV	NAV
Coal Hot Water Heaters[a]		18	NAV	160	NAV	NAV
Coal Furnaces[a]		480	NAV	230	NAV	NAV
Coal Stoves[a]		3600	NAV	180	NAV	NAV
Oil						
Residual Fuel Oil		15	1.4	170	NAV	NAV
Distillate Fuel Oil		16	0.7	65	NAV	NAV
Furnaces		16	5.8	59	0.2	NAV
Propane/Butane Furnaces[a]		10	1.1	47	NAV	NAV
Natural Gas						
Furnaces		18	NAV	43	NAV	NAV
Gas Heaters[a]		10	1	47	NAV	NAV
Wood						
Wood Pits[a]		4900	200	150	NAV	NAV
Fireplaces		11000	NAV	110	NAV	NAV
Stoves	Conventional	10000	210	120	NAV	NAV
	Non-catalytic	6100	NAV	NAV	NAV	NAV
	Catalytic	4500	380	87	NAV	NAV
	Pellet, Certified	1700	NAV	600	NAV	NAV
	Pellet, Exempt	2300	NAV	NAV	NAV	NAV
Masonry Heater	Exempt	6500	NAV	NAV	NAV	NAV

Source: US EPA (1995).

(a) Adapted from Radian, 1990.

TABLE 14.4-7
COMMERCIAL SOURCE PERFORMANCE

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Coal Boilers[a]		200	10	240	NAV	NAV
Oil						
Residual Fuel Oil/Shale Oil		15	1.4	170	0.3	NAV
Distillate Fuel Oil		16	0.7	65	0.4	NAV
Waste Oil Space Heaters	Vaporising Burner	5.0	NAV	33	NAV	NAV
	Atomising Burner	6.3	NAV	48	NAV	NAV
LPG Boilers	Propane	8.4	NAV	71	NAV	NAV
	Butane	12	NAV	70	NAV	NAV
Natural Gas						
Boilers		9.4	1.2	45	2.3	NAV
Wood						
Incineration - high efficiency[a]		440	NAV	130	NAV	NAV
Waste						
Mass Burn Waterwall		22	NAV	170	NAV	NAV
Combustors		NAV	NAV	NAV	NAV	NAV
MSW Boilers[a]		19	NAV	460	NAV	NAV

Source: US EPA (1995).

(a) Adapted from Radian, 1990.

TABLE 14.4-8
UTILITY EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss[(a)] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[(b)]
Low Excess Air (LEA)	-0.5	+	+	15	NAV	NAV	1970
Overfire Air (OFA) - Coal	0.5	+	+	25	NAV	NAV	1970
OFA - Gas	1.25	+	+	40	NAV	NAV	1970
OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Low NO_x Burner (LNB) - Coal	0.25	+	+	35	NAV	NAV	1980
LNB - Tangentially Fired	0.25	+	+	35	NAV	NAV	1980
LNB - Oil	0.25	+	+	35	NAV	NAV	1980
LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Cyclone Combustion Modification	0.5	NAV	NAV	40	NAV	NAV	1990
Ammonia Injection	0.5	+	+	60	NAV	NAV	1985
Selective Catalytic Reduction (SCR) - Coal	1	8	+	80	NAV	NAV	1985
SCR - Oil, AFBC	1	8	+	80	NAV	NAV	1985
SCR - Gas	1	8	+	80	60	NAV	1985
Water Injection - Gas Turbine Simple Cycle	1	+	+	70	NAV	NAV	1975
SCR - Gas Turbine	1	8	+	80	60	NAV	1985
Retrofit LEA	-0.5	+	+	15	NAV	NAV	1970
Retrofit OFA - Coal	0.5	+	+	25	NAV	NAV	1970
Retrofit OFA - Gas	1.25	+	+	40	NAV	NAV	1970
Retrofit OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Retrofit LNB - Coal	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Oil	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Burners Out of Service	0.5	+	+	30	NAV	NAV	1975

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

TABLE 14.4-9
INDUSTRIAL BOILER EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss[a] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[b]
Low Excess Air (LEA)	-0.5	+	+	15	NAV	NAV	1970
Overfire Air (OFA) - Coal	0.5	+	+	25	NAV	NAV	1970
OFA - Gas	1.25	+	+	40	NAV	NAV	1970
OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Low NO_x Burner (LNB) - Coal	0.25	+	+	35	NAV	NAV	1980
LNB - Oil	0.25	+	+	35	NAV	NAV	1980
LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Flue Gas Recirculation	0.5	+	+	40	NAV	NAV	1975
Ammonia Injection	0.5	+	+	60	NAV	NAV	1985
Selective Catalytic Reduction (SCR) - Coal	1	8	+	80	NAV	NAV	1985
SCR - Oil, AFBC	1	8	+	80	NAV	NAV	1985
SCR - Gas	1	8	+	80	60	NAV	1985
Retrofit LEA	-0.5	+	+	15	NAV	NAV	1970
Retrofit OFA - Coal	0.5	+	+	25	NAV	NAV	1970
Retrofit OFA - Gas	1.25	+	+	40	NAV	NAV	1970
Retrofit OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Retrofit LNB - Coal	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Oil	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Gas	0.25	+	+	50	NAV	NAV	1980

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

TABLE 14.4-10
KILN, OVENS, AND DRYERS EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss[a] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[b]
LEA - Kilns, Dryers	-6.4	+	+	14	NAV	NAV	1980
LNB - Kilns, Dryers	0	+	+	35	NAV	NAV	1985
SCR - Coke Oven	1.0	8	+	80	60	NAV	1979
Nitrogen Injection	NAV	NAV	NAV	30	NAV	NAV	1990
Fuel Staging	NAV	NAV	NAV	50	NAV	NAV	1995

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

TABLE 14.4-11
RESIDENTIAL AND COMMERCIAL EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss[(a)] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[(b)]
Catalytic Woodstove	-44	90	90	-27	NAV	NAV	1985
Non-Catalytic Modified Combustion Stove	-30	15	50	-5	NAV	NAV	1985
Flame Retention Burner Head	-9	28	NAV	NAV	NAV	NAV	
Controlled Mixed Burner Head	-7	43	NAV	44	NAV	NAV	
Integrated Furnace System	-12	13	NAV	69	NAV	NAV	
Blueray Burner/Furnace	-12	74	NAV	84	NAV	NAV	
M.A.N. Burner	-13	NAV	NAV	71	NAV	NAV	1980
Radiant Screens	-7	62	NAV	55	NAV	NAV	
Secondary Air Baffle	NAV	16	NAV	40	NAV	NAV	
Surface Comb. Burner	NAV	55	NAV	79	NAV	NAV	
Amana HTM	-21	-55	NAV	79	NAV	NAV	
Modulating Furnace	-7	NAV	NAV	32	NAV	NAV	
Pulse Combuster	-36	NAV	NAV	47	NAV	NAV	
Catalytic Combuster	-29	NAV	NAV	86	NAV	NAV	
Replace Worn Units	NAV	65	NAV	NAV	NAV	NAV	
Tuning, Seasonal Maintenance	-2	16	NAV	NAV	NAV	NAV	
Reduced Excessive Firing	-19	14	NAV	NAV	NAV	NAV	
Reduced Excessive Firing with New Retention Burner	-40	14	NAV	NAV	NAV	NAV	
Positive Chimney Dampers	-8	11	NAV	NAV	NAV	NAV	
Increased Thermostat Anticipator	-1	43	NAV	NAV	NAV	NAV	
Night Thermostat Cutback	-15	17	NAV	NAV	NAV	NAV	
Low Excess Air	-0.8	NAV	NAV	15	NAV	NAV	1970
Flue Gas Recirculation	0.6	NAV	NAV	50	NAV	NAV	1975
Over-fire Air	1	NAV	NAV	20-30	NAV	NAV	1970
Low NO_x Burners	0.6	NAV	NAV	40-50	NAV	NAV	1980

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Source: Radian, 1990.

5

ALTERNATE METHODS FOR ESTIMATING EMISSIONS

No alternate methods have yet been approved by the Greenhouse Gas Committee of the Emission Inventory Improvement Program.

6

QUALITY ASSURANCE/QUALITY CONTROL

Quality assurance (QA) and quality control (QC) are essential elements in producing high quality emission estimates and should be included in all methods to estimate emissions. QA/QC of emissions estimates are accomplished through a set of procedures that ensure the quality and reliability of data collection and processing. These procedures include the use of appropriate emission estimation methods, reasonable assumptions, data reliability checks, and accuracy/logic checks of calculations. Volume VI of this series, *Quality Assurance Procedures*, describes methods and tools for performing these procedures.

Uncertainties in the estimation methods for the various emission sources are discussed above throughout section 4.

6.1 DATA ATTRIBUTE RANKING SYSTEM (DARS) SCORES

DARS is a system for evaluating the quality of data used in an emission inventory. To develop a DARS score, one must evaluate the reliability of eight components of the emissions estimate. Four of the components are related to the activity level (e.g., the amount of fuel combusted). The other four components are related to the emission factor (e.g., the amount of N_2O or methane emitted per unit of fuel combusted). For both the activity level and the emission factor, the four attributes evaluated are the measurement method, source specificity, spatial congruity, and temporal congruity. Each component is scored on a scale of zero to one, where one represents a high level of reliability. To derive the DARS score for a given estimation method, the activity level score is multiplied by the emission factor score for each of the four attributes, and the resulting products are averaged. The highest possible DARS composite score is one. A complete discussion of DARS may be found in Chapter 4 of Volume VI, *Quality Assurance Procedures*.

The DARS scores provided here are based on the use of the emission factors provided in this chapter, and activity data from the sources referenced in the various steps of the methodology. If a state uses state data sources for activity data, the state may wish to develop a DARS score based on the use of state data.

TABLE 14.6-1

DARS SCORES: N_2O EMISSIONS FROM STATIONARY SOURCE COMBUSTION (SIMPLE METHOD)

Measurement	5	The emission factors are based on measurements at a representative sample of stationary source combustion facilities, but have large uncertainty ranges (De Soete, 1993)	9	Fuel purchases are measured using top-down statistics.	0.45
Source Specificity	7	The emission factors were developed specifically for the intended source category, but do not account for different emission rates from various combustion technologies.	5	Fuel purchases are somewhat correlated to the emissions process.	0.35
Spatial Congruity	9	The emission factors were developed for global use, but spatial variability is expected to be low.	8	States use state-level activity data to estimate state-wide emissions, but there are minor cross-state sales by retailers.	0.72
Temporal Congruity	8	The emissions factors were derived using sampling for only part of a year, but temporal variability is expected to be low.	9	States use annual activity data to estimate annual emissions.	0.72
				Composite Score	**0.56**

TABLE 14.6-2

DARS SCORES: N_2O AND CH_4 EMISSIONS FROM STATIONARY SOURCE COMBUSTION (COMPLEX METHOD)

DARS Attribute Category	Emission Factor Attribute	Explanation	Activity Data Attribute	Explanation	Emission Score
Measurement	8	The emission factors are based on measurements at a sample of facilities (IPCC 1997)	9	Fuel purchases are measured using top-down statistics.	0.72
Source Specificity	10	The emission factors were developed specifically for the intended source category.	5	Fuel purchases are somewhat correlated to the emissions process.	0.50
Spatial Congruity	9	The emission factors were developed for global use, but spatial variability is expected to be low.	8	States use state-level activity data to estimate state-wide emissions, but there are minor cross-state sales by retailers.	0.72
Temporal Congruity	8	The emissions factors were derived using sampling for only part of a year, but temporal variability is expected to be low.	9	States use annual activity data to estimate annual emissions.	0.72
				Composite Score	**0.67**

7

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